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Alternative Energy Storage for Wind Power: Coal Plants with Amine-based CCS

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Abstract

This paper analyses the performance of a hybrid system consisting of an existing coal plant with post-combustion amine based CCS with amine storage, and a co-located wind farm. The amine storage system allows storage of the CO_2-rich amine solution to reduce the energy penalty of the CCS system at times of high electricity prices/high demand. The amine-rich solution can be regenerated at an enhanced rate when electricity prices are relatively low or when wind power output exceeds the transmission capacity of the connector lines: effectively providing 'storage' for wind power and a mechanism for muting the variability of wind power output. Using prices and wind data from the eastern region of U.S., we find the optimal configuration and operation, profits, Cost of CO_2 Capture (CoC), and Levelized Cost of Electricity (LCOE) of the hybrid system, with and without constraints on the variability of the net power output. We find that favourable conditions regarding price arbitrage opportunities and wind power output variability -same or lower variability than that observed in ~70% of sites in the EWITS database- allow the hybrid system to be more cost effective than other alternatives for reducing CO_2 emissions from an existing coal-fired power plant and/or integrating wind power as a component of a base-load plant. For example, hybrid systems with up to 10% of the total installed capacity from the wind farm, can operate as a base-load plant, and still be more profitable and have lower LCOE and CoC values, than a continuously operating coal plant with a CCS retrofit. Using an existing plant as a component of a hybrid system can result in lower CoC than replacing it with a new Natural Gas Combined Cycle power plant -assuming natural gas prices are in the range 6-8 \$/MMBtu.

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Keywords: Amine Storage; Hybrid System; Wind Power Integration; Optimized Operation; flexible CCS

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1. Introduction

One of the major drawbacks of the use of CCS technology in fossil fired power plants is its associated energy penalty which causes a reduction of net power output in the range of 20-40% and accounts for a significant portion of the CCS plant operating expenses [1,2]. Flexible operation of post-combustion amine-based CCS systems either bypassing the CCS capture unit to vent CO_2, or enabling amine-storage, can decrease the associated costs of this penalty by adjusting the CO_2 capture rate in order to take advantage of electricity price arbitrage opportunities [3-14].

The amine storage system allows storage of the CO_2-rich amine solution in a tank to delay incurring the energy penalty associated with the amine-stripper's operation, without venting the CO_2 emissions captured. By postponing the process of amine regeneration from times of high electricity prices to times of low prices, the economic costs associated to the CCS energy penalty can be substantially reduced.

The economics and environmental performance of a CCS system with amine-storage can be further improved by co-locating a wind power farm, and operating the strippers at an enhanced rate to regenerate stored amine when wind power output exceeds the transmission capacity of the connector lines.

Stand-alone wind farms are a source of intermittent supply of electricity which affects the reliability and reserve requirements of the power system. If sized optimally, the coal-wind hybrid system under consideration can be dispatched to maximize profits given electricity prices and wind power conditions. By providing flexibility to reduce or increase the power that flows from the wind farm and coal plant to the grid, the CCS system provides a form of 'storage' for wind power. Also, connection costs of the new wind farm can be reduced by using the spare transmission capacity that results from the reduction in electricity output of a coal plant when it is retrofitted with CCS.

In this paper we study the economics of post-combustion amine based CCS retrofits with amine-storage in existing coal plants for facilitating the integration of wind power into a system. We focus on existing plants because the capital costs of enabling flexible operation in these plants is lower than in new ones, due to the fact that in retrofit plants the generators and low pressure steam turbines are already sized to optimally handle all the steam that would be generated in a plant without CCS. Also, about 20% of the net annual generation in the US is provided by existing sub-critical coal plants that still have more than 25 years of active life ahead and nameplate capacities greater than 350 MW. Since a sudden retirement of such a large portion of the power system would severely compromise the cost-effectiveness and reliability of the grid, the approach explored here can be an important tool to reduce the CO_2 emission levels of a power system that is on its way to incorporating more renewable energy.

Recent studies indicate that besides reducing the costs associated to the CCS' energy penalty, enabling flexible capture also increases the range of operation of the power plants (by reducing the minimum power output required to keep the plant online [11]), and flexible CCS may be used to satisfy peak power demand [9], provide ancillary services, obtain higher profits [9-11,13,14], and offset the intermittent nature of renewable sources of power such as wind and solar [10-11].

Most of the previous studies analysing flexible operation of stand-alone CCS [3-10, 12-14] and hybrid systems [11, 16-17], assume operations occur according to an optimization algorithm that maximizes profits [3,7-8,11,13,16-17], and most studies [3-4,6-11,16] report the percentage increase in profits and/or Net Present Values (NPV) under different CO_2 tax scenarios, as the primary metric to evaluate the relative benefit of the system.

In this paper, rather than making assumptions about potential CO_2 tax levels we choose to estimate the Cost of CO_2 Capture (CoC) and Levelized Cost of Electricity (LCOE) for the flexible CCS system or the corresponding hybrid system, and use these metrics as a basis for comparison of different configurations and as a way to assess the economic value of flexible CCS relative to other CO_2 emission reduction strategies (such as replacing existing coal plants with natural-gas fired power plants). Similar to those studies, we assume operation of the plants follows the prescription of an optimization model that maximizes profits, but different from them we also solve for the optimal size of the components of the hybrid system (wind farm, storage tanks, and regeneration unit), and we analyse the effects of capital costs, constraints on power output variations, CO_2 emissions constraints, wind power variability, and electricity prices variability on the optimum size and economic benefits of the hybrid system.

A parallel analysis of a hybrid system with partial capture (i.e. bypass of the flue gas) instead of amine storage has also been performed by the authors in [18].

2. Method, data and assumptions

We assume the specifications of the existing coal plant in the hybrid system are similar to those of the Powerton Plant, an existing sub-critical coal plant in Illinois (eGrid[19]), and use the IECM software [20] to estimate CCS energy penalty, capital costs and O&M costs that would result if the plant is retrofitted with post-combustion amine-based CCS with a 90% capture rate. Assumptions on coal plant ramp-rate and minimum generation requirements are from [21], and coal prices are assumed to be those projected by the Annual Energy Outlook [22].

Capital costs and Annual Operating Expenses (AOE) of wind farms are from [23]. SynTiSe [24], a Markov Chain Monte Carlo application [25] was trained with EWITS [26] data to generate long-term synthetic time series of wind power output. We assume the lifespan of the hybrid system is 20 years -the same as that of an onshore wind farm [23], and hourly electricity Locational Marginal Prices (LMP) from multiple hubs in PJM in year 2013 come from [27]. We assume the maximum CO_2 capture of the CCS system is 90% [1-3], and assume the amine stripper can only operate within 20-100% of its maximum capability. We do not allow the stripper unit to operate below 20% capacity to prevent degradation of system components due to frequent on/off operations and to avoid large start-up times to resume operation after complete shut-down, because this may reduce the ability of the CCS plant to smooth out the combined power output of the hybrid system at times of low wind power production [7-8]. It is also assumed that additional transmission capacity is not added to the system when the wind farm is installed, and instead, only the spare transmission capacity resulting from the CCS retrofit in the existing coal plant is used to connect an optimally sized wind farm to the power system. We simulate operation of the hybrid system every 10 minutes during one year and adjust all capital and fixed costs for the LCOE and CoC calculations.

A linear optimization model allows identification of optimum values for the size of the amine storage tank, wind farm, the factor by which the CCS unit components need to be scaled up to enable amine-storage and enhanced regeneration, the operation schedule of the CCS unit, and dispatch of wind and coal-based power.

The decision variables are:

$\mathrm{O_{w,t}}$: Wind power dispatched at time interval t (MW)

$\mathrm{O_{c,t}}$: Power generated by coal plant at time interval t (including steam power in equivalent MWs for regeneration of CO_2-rich amine) (MW)

$\mathrm{r_t}$: Multiplying factor to obtain total energy penalty of the stripper at time interval t under each regeneration mode:

$\mathrm{r_t} \in [0.2,1) \rightarrow$ “Storage Mode”: A fraction of the CO_2-rich amine solution is stored in the tank, so the energy penalty of regeneration is reduced between 0%-80%.

$\mathrm{r_t} = 1 \quad \rightarrow$ “Regular Mode”: The CO_2-rich amine solution generated at the current time instant is regenerated in the stripper. Enhanced regeneration to simultaneously regenerate stored CO_2 rich amine solution is not performed, and energy penalty is not reduced

$\mathrm{r_t} \in (1, \mathrm{SF}] \rightarrow$ “Regeneration Mode”: Enhanced regeneration to simultaneously regenerate stored CO_2 rich amine solution is performed and energy penalty increases by factor $\mathrm{r_t}$ corresponding to time t

$\mathrm{H_S^{max}}$: Size of the amine storage tank in terms of number of maximum consecutive time intervals in which the system can operate in storage mode (in hours/minutes depending upon the time resolution used). This decision variable is constrained to take non-negative values only.

SF : Scaling Factor (SF) is the fractional increase in corresponding CCS system component sizes to enable amine storage. This decision variable is constrained to take non-negative values only.

$O_w^{nameplate}$: Optimum nameplate capacity of co-located wind farm (MW)

The parameters used as input to the model are:

$E_{stripper}$: Energy penalty due to stripper operation: Power used from steam being diverted between the LP and HP levels of turbines for regeneration in the "regular" mode (MW)

E_{other} : Energy penalty due to absorption operation of CCS, base plant use, operation of FGD, NO_x controller etc. (MW)

LMP_t : Locational Marginal Price ($/MWh)

AOE : Annual Operating Expenses of the wind farm ($/MWh)

C_{fuel} : Cost of fuel (coal) per MWh of electrical energy generated (depends upon the heat rate of the plant) ($/MWh)

$O\&M_{coal}^{var}$: Variable O&M cost of operating the coal plant excluding cost of fuel ($/MWh)

$CC_{Storage}$: Annualized Capital Cost of amine storage tank per unit of storage capacity (expressed in minutes or hours of continuous operation in the storage mode) ($/hr/yr)

CC_{wind} : Annualized Capital Cost of wind farm per MW of installed capacity ($/MW/yr)

SF_{costs} : Additional annualized capital costs due to scaling up by SF some components of the CCS system to incorporate amine storage ($/yr)

$O_C^{nameplate}$: Nameplate capacity of the coal plant (MW)

$O\&M_{coal}^{fixed}$: Fixed O&M cost of coal plant ($/yr)

CC_{CCS} : Annualized Capital Cost of the coal-CCS plant ($/yr)

T : Number of time periods in the planning horizon (i.e. 8,760 one-hour periods in one year)

The objective is to maximize the annual profit (Ω) of the hybrid system:

$$\max_{O_{w,t}, O_{c,t}, O_w^{nameplate}, r_t, H_S^{max}, SF} \Omega \tag{1}$$

$$\Omega = \sum_{t=1}^{T} [\{O_{w,t} + O_{c,t} - E_{other} - E_{stripper} * r_t\} * LMP_t - (C_{fuel} + O\&M_{coal}^{var}) * O_{c,t} - AOE * O_{w,t}] - CC_{Storage} * H_S^{max} - CC_{wind} * O_W^{nameplate} - SF_{costs} * (SF - 1) \tag{2}$$

The optimization is performed subject to constraints on operation of the coal plant, the wind farm, the CCS system, as well as policy and power system operation requirements. The performance of the hybrid system is measured in terms of the Levelized Cost of Electricity (LCOE) and the Cost of CO_2 Capture (CoC) defined as follows:

Levelized Cost of Electricity (\$/MWh) =

$$\frac{CC_{wind}+\sum_{t=1}^{T} O_{w,t}*AOE + CC_{CCS} + O\&M_{CCS} + CC_{storage}*H_S^{max} + O\&M_{Amine\ Storage} + \sum_{t=1}^{T} O_{c,t}*(O\&M_{Coal}^{var}+C_{fuel}) + O\&M_{Coal}^{fixed} + Revenue\ Loss_{CCS}}{\sum_{t=1}^{T}(O_{w,t}+O_{c,t}-E_{stripper}*r_t-E_{other})} \quad (3)$$

Where:

$Revenue\ Loss_{CCS}$: Annual loss of revenue due to the reduction in net power output caused by CCS unit operation (\$/yr). This quantity is estimated as $\sum_{t=1}^{T}(E_{stripper} * r_t + E_{other}) * LMP_t$

$$\text{Cost of } CO_2 \text{ Capture (\$/ton)} = \frac{LCOE_{Hybrid\ System} - LCOE_{Coal\ Plant\ w/o\ CCS\ retrofit}}{CO_2Emissions_{Coal\ plant\ w/o\ CCS\ retrofit} - CO_2Emissions_{Hybrid\ System}} \quad (4)$$

3. Results

Table 1 summarizes the performance of the hybrid system under varying constraints regarding variability on power output and size of wind farm, and assuming electricity prices are those of the Chicago Hub in PJM , and wind power data has the same variability of the EWITS site #4431 (Refer to section I of [28]).

The BAU scenario consists of an existing coal plant retrofitted with a continuous operation CCS unit and may be used for comparison with the remaining scenarios in table 1. A comparison of the BAU scenario with scenarios 1 and 2 indicates that higher profits (Ω*) and lower values of LCOEs and CO_2 Capture Costs can be obtained from flexible operation of CCS relative to the continuous operation case. The reduction in costs quantifies the benefit from price arbitrage opportunities.

Allowing the net power output to vary in an unconstrained manner leads to lower costs and higher profits as is evident from the comparison of scenarios 1 and 2. Constraining the net power output to vary within 10% of its nameplate capacity in scenario 1 rather than allowing unlimited variations (scenario 2) leads to a 2.3\$/ton and 2\$/MWh increase, and a 16% increase in the values of LCOE, CoC and profits respectively, due to a reduction in price arbitrage opportunities. Additional expenses are also incurred in Scenario 1, since the system requires a larger storage tank compared to scenario 2 in order to maintain the net power variability within 10% of the nameplate capacity.

If unconstrained variation of net power is allowed, the addition of a wind farm leads to a decrease in loss of revenue due to CCS energy penalty, and an increase in net power generated by the hybrid system since wind power can be used to substitute for the decrease in power output from the coal unit due to CCS operation. In fact there is a reduction of 2.8 \$/MWh and 3 \$/ton in the LCOE and CoC metric when comparing scenario 2 with scenario 6.

The effect of constraints on maximum variability of system's power output on the size of the storage tank is a bit ambiguous. On one side, when it is optimal to integrate large wind farms into the system, it is also optimal to have larger size of amine storage tanks (scenario 4 vs scenario 5) to perform price arbitrage and contain the power output variability, but completely relaxing the constraint on allowed variability of net power output may lead to smaller amine storage tanks for larger optimal wind farm configurations (compare scenarios 5 and 6).

Table 1. Performance and optimal configuration of the hybrid system model in the Chicago Hub of PJM interconnect under varying assumptions on allowed variability of net power output and restrictions on building the co-located wind farm

Assumptions			Results						
Scenario	Max. Allowed Variability (in MW/hr and as % of nameplate capacity)	Max WF Size allowed	Nameplate Capacity of Hybrid System (MW) = Coal Plant Nameplate Capacity + Optimum Size of Wind Farm	Optimum Size of Wind Farm (in MW and as % of nameplate capacity)	Optimum size of the storage tank (in terms of max. number of consecutive storage operation intervals in hrs)	Levelized Cost of Electricity (LCOE) in \$/MWh	Cost of CO_2 Capture (\$/ton)	The value of Ω* (\$/yr)	The value of Ω (\$/yr)
BAU	No variability allowed (0 MW/hr)	0	1786.5	No wind farm installed for these scenarios	0	135.5	66.6	-47,105,381	134,194,619
1	178.5 MW/hr or 10% (approx.) of nameplate capacity				6.8	130.6	61.2	-28,410,043	152,889,957
2	No Upper Limit				8.1	128.6	58.9	-24,508,192	156,791,808
3	No variability allowed (0 MW/hr)	No upper Limit	1786.5	0	0	135.5	66.6	-47,105,381	134,194,619
4	178.5 MW/hr or 8% (approx.) of nameplate capacity		2194.2	405.9 (18% of nameplate capacity)	6.9	133.7	64.6	-26,532,423	154,767,577
5	500 MW/hr or 26% of nameplate capacity		2497	711.4 (28% of nameplate capacity)	7.2	127.3	57.5	-21,538,969	159,761,031
6	No upper limit		2657.5	871 (32% of nameplate capacity)	6.6	125.8	55.9	-14,556,651	166,743,349
Ω* = Ω - Annualized Capital Cost for the CCS not considering expenses for amine storage - Annual Fixed O&M Costs for the Coal Plant									

In the presence of constraints on net power variability of the hybrid system the addition of the wind power in the system is optimal in scenarios 4 and 5 and this leads to increased profits due to both a reduction of energy penalty and increased revenue generated from the sale of additional electricity during high price durations, but these scenarios are less profitable than scenario 6. However, the comparison of scenario 4 with scenario 1 leads to an interesting observation: although the profits are higher for scenario 4 relative to scenario 1, the LCOE and CoC are higher in scenario 4. This is because additional costs incurred due to the installation of the wind farm are not offset by the reduction in the cost of the CCS energy penalty alone. Since the LCOE and CoC calculations take into account only the additional electricity generated by wind but not the increase in revenue, due to sale of wind power during high electricity durations, for scenario 4, the numerator of the LCOE and the CoC increase at a faster rate than the denominator due to addition of wind power. Regardless of relatively high LCOE and CoC values in scenario 4, it is clear that due to the presence of high electricity prices and consequently high revenue earned from the sale of additional wind power, it is profitable to install a 405.9 MW wind farm even when the net power of the hybrid system is constrained to vary within 8% of the total nameplate capacity of the system. This observation is important because it indicates that incorrect conclusions may be obtained from the use of LCOE and CoCs as the sole metrics for the evaluation of profitability of a hybrid system like the one examined in this paper.

3.1 Quantifying the effects of electricity price variability wind power ramp characteristics: A study of the performance of the hybrid system in the PJM interconnect

The two main factors that affect the profitability of the hybrid system when no variability of the net power output is allowed are: a) the benefits from price arbitrage (which depend on the variability of the electricity price time series) and b) the ramp characteristics of the available wind power (reflecting the degree of intermittency of wind power). We quantify these factors using the *Average Price Differential* (APD) and the *Mean Aggregated Ramp Magnitude as Percentage of Name Plate Capacity* (MARMAP).

The APD metric is defined as the average value of mean electricity price differentials during every instance of continuously increasing or decreasing values of electricity prices. A price differential is defined as the absolute difference between electricity prices at consecutive time intervals. A high APD value indicates better price arbitrage opportunities. The MARMAP metric is defined as the average of the magnitude of all *ramping events* (defined as those instances when changes in wind power output exceed the ramp-up/down capacity of the coal plant with the CCS retrofit) expressed as a percentage of the nameplate capacity of the wind farm. A high MARMAP value indicates high ramp characteristics (see sections VII and IX in [28] for detailed definition of APD and MARMAP metrics respectively).

To examine the effect of a choice of wind site, four EWITS [26] sites with MARMAP values of 10%, 25%, 50% and 98% - which correspond to ~70%, ~10%, ~15%, and ~5% of the total number of wind sites in the US Eastern Interconnect identified by EWITS- were used as inputs to obtain for each of them 15 sets of wind power time series using the SynTiSe software. Tables 2-4 report the range of LCOEs, CoCs and optimum configuration as well as the corresponding median values corresponding to the 15 observations for each MARMAP value.

Table 2 summarizes the costs and optimal configuration of the hybrid system when operating in the Dominion Hub and the AEP General Hub which were found to have the highest and lowest APD values for the electricity prices in 2013, for varying levels of wind power ramp characteristics.

Higher APD value caused lower LCOEs, lower CoCs, larger wind farm sizes and larger size of amine storage tanks due to better price arbitrage opportunities. Low MARMAP values led to larger wind farm sizes with smaller size of amine storage tanks.

In the Dominion hub, price arbitrage opportunities allow integrating wind farms with MARMAP values of up to 25%, even under the assumption that the power output of the hybrid system must remain fixed. For the AEP general hub, the benefits from price arbitrage are too low to offset the additional expenses of enabling amine storage and installing a wind farm, when the net power output of the hybrid system is forced to remain constant, and as a result optimal configuration of the system does not include installing a wind farm.

3.2 Sensitivity analysis: Analysing the effect of capital costs, PTC and CCS energy penalty estimates

The effect of capital costs, PTC and CCS energy penalty estimates are analysed in this section under the assumption that the hybrid system needs to perform as a baseload plant (i.e. no power output variability is allowed). The electricity price time series is obtained from the Dominion Hub in the PJM interconnect. This time series was found to generate sufficient price arbitrage opportunities and revenues from sale of additional wind based electricity to justify investments in amine storage and a co-located wind farm, and hence enabled us to observe the effect of these factors on the wind farm sizes and the size of the amine storage tank.

1. Effect of capital cost of CCS (with amine storage):

Higher CCS capital costs results in higher LCOE, smaller wind farms and less storage. For higher MARMAP, the reduced costs of CCS led to higher wind farm sizes and a subsequent increase in storage tank to maintain steady net power output. Information about the effect that reducing CCS capital costs may have on increasing opportunities for wind power integration, can be obtained from comparing the installed capacity of the wind farm for two scenarios of capital costs for CCS retrofits. In the case study for wind sites with lower variability (10% MARMAP), a 50% reduction in the capital costs of the CCS retrofit allows integrating 427-430MW of wind -as baseload- instead of 241-255MW that can be integrated under current costs. This corresponds to a cost for wind power integration in the range of 1,265-1,355 $/kW of wind installed capacity. These costs are lower than EPRI cost estimates of several other forms of energy storage that could make a wind-farm behave as a baseload plant such as pumped hydro, flywheel, and batteries like lead acid, Li-ion,NaS, Vanadium Redox and Zinc Bromide [29,30]. The same observation does not hold for wind sites with higher variability (>=25% MARMAP) because of increased expenses incurred to increase storage capacity necessary to smooth out the higher variability of wind power.

Table 2. An analysis of the performance of the hybrid system under varying opportunities for price arbitrage and wind power ramp characteristics quantified by the APD and MARMAP metrics respectively in the PJM interconnect. The net power output of the hybrid system was not allowed to vary.

PJM Hub corresponding to LMP Time Series Used		Dominion Hub (APD = 10.06 $/MWh)				AEP General Hub (APD = 7.05 $/MWh)			
Ramp characteristics of the Wind Site		Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 50%	Wind Site MARMAP Value: 98%	Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 50%	Wind Site MARMAP Value: 98%
LCOE ($/MWh)	Range	119-123.2	122.0-125.9	129.1	129.1	151	151	151	151
	Median	121.2	123.5	129.1	129.1	151	151	151	151
Cost of CO_2 Capture ($/ton)	Range	48.3-52.9	51.6-55.9	59.5	59.5	83.9	83.9	83.9	83.9
	Median	50.76	53.3	59.5	59.5	83.9	83.9	83.9	83.9
Optimum Size of Wind Farm (MW)	Range	241-255.5	21.6-32.1	0	0	0	0	0	0
	Median	247.2	29.1	0	0	0	0	0	0
Optimum Size of Amine Storage System in Equivalent Hours	Range	3.1 - 4.8	5.5 - 6.3	0	0	0	0	0	0
	Median	4.2	6.1	0	0	0	0	0	0

3.3. Effect of Wind Power Capital Costs

Lower wind costs result in lower LCOE and CoC, higher wind farm sizes, and higher amine storage tank sizes to smooth out the intermittency of wind power. However the increase in size of wind farm and reduction in

Table 3. An analysis of the performance of the hybrid system in the Dominion Hub for different values of costs of CCS with amine storage capabilities and for wind farm costs. The net power output of the hybrid system was not allowed to vary.

Scenario		Change in Capital and O&M costs of CCS unit (including the amine storage system)				Change in Capital and O&M costs of the wind farm			
		Reduced by 50% relative to the BAU scenario		Increased by 50% relative to the BAU scenario		Reduced by 50% relative to the BAU scenario		Increased by 50% relative to the BAU scenario	
Ramp characteristics of the Wind Site		Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%
LCOE ($/MWh)	Range	102.3 - 105.9	111.9 - 114.9	148.3 - 153.4	133.0 - 137.4	107.8 - 110.3	118.6 - 120.7	129.1	129.1
	Median	103.8	113.3	149.9	135.2	108.9	119.9	129.1	129.1
Cost of CO_2 Capture ($/ton)	Range	30.3- 34.3	41.0 - 44.3	81.4 - 87.1	64.4 - 69.3	36.4 - 39.2	48.4 - 50.8	59.5	59.5
	Median	32	42.6	83.2	66.89	37.6	49.9	59.5	59.5
Optimum Size of Wind Farm (MW)	Range	426.9 - 430.8	46.7 - 49.2	100.6 - 109.8	12.5 - 16.4	332.6 - 334.7	88.3 - 91.6	0	0
	Median	429.4	48.6	105.7	14.8	333.9	89.2	0	0
Optimum Size of Amine Storage System in Equivalent Hours	Range	8.1 -9.5	10.6 - 12.3	1.4 - 2.0	0.5 -0.8	5.8 -6.4	8.1 - 9.0	0	0
	Median	8.8	11.2	1.8	0.7	6.2	8.7	0	0

costs are both of a lower magnitude relative to the case with reduced CCS capital costs because increased wind capacity must be made less intermittent with more amine storage, and this results in an additional expense.

3.4. Effect of CCS Energy Penalty

For a higher energy penalty more power transmission capacity is made available in the connector lines. This increases the limit for the size of wind farm, so its optimal size and that of the amine storage increase. However the resulting loss of revenue due to a higher energy penalty and increased expenses from larger sizes of amine storage tanks results in higher overall CoC. Scenarios with MARMAP values beyond 25% are not reported because the optimal size of wind power being installed for the 40% CCS energy penalty case is 0MW.

3.5. Effect of PTC

Lower costs and higher wind farm sizes are observed when a PTC is offered but once again increase in size of wind farm and reduction in costs are both of a lower magnitude relative to the case when CCS capital costs are reduced because increased wind power must be made less intermittent with larger amine storage capacity and this incurs an additional expense for the PTC scenario.

Table 4. An analysis of the performance of the hybrid system for variations in the CCS energy penalty and PTC estimates in the Dominion Hub. The net power output of the hybrid system was not allowed to vary.

Scenario		CCS Energy Penalty Value				PTC offered at the rate of 2.3 cents/KWh for electricity generation from the co-located wind farm	
		20% of net power output		40% of net power output			
Ramp characteristics of the Wind Site		Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%	Wind Site MARMAP Value: 10%	Wind Site MARMAP Value: 25%
LCOE ($/MWh)	Range	107.3 - 112.4	119.4 - 122.3	132.6 - 139.1	138.3 - 143.7	98.6 - 106.9	113.9 - 115.0
	Median	110.7	120.3	136.1	140.5	101.8	114.5
Cost of CO_2 Capture ($/ton)	Range	36.4 - 41.3	49.0 - 52.5	64.0 - 71.1	70.9 - 76.3	25.3-35.4	43.2 - 44.4
	Median	39.6	50.3	67.8	72.8	29.7	43.9
Optimum Size of Wind Farm (MW)	Range	180.9 -183.4	18.6 - 20.0	332.6 - 338.4	40.4 - 47.6	397.9 - 405.9	137.8 - 143.7
	Median	182.7	19.7	336.9	44.4	400.7	140.8
Optimum Size of Amine Storage System in Equivalent Hours	Range	2.7 - 3.3	4.6 - 5.2	5.7 - 6.7	7.9 - 8.7	4.8 - 5.3	5.7 - 6.1
	Median	3	5	6	8.4	5.1	5.9

4. Conclusions

Results show that the economics of investment in amine storage to enable flexible operation in coal plants with CCS retrofits depend to a great extent on the potential benefits from electricity price arbitrage opportunities. For electricity price time series that justify investments in amine storage the hybrid system enables considerable quantities of wind power integration (within the range of 18-32% of the nameplate capacity for operation of a 1786.5 MW coal plant with CCS retrofit in the Chicago Hub), and significant increase in profits and decrease in LCOE and CoC, when compared to a CCS retrofitted coal plant operating continuously.

The potential for wind power integration as a component of a base-load plant is significantly dependent on the variability of the wind power output. In general, price arbitrage opportunities like those observed in PJM's Dominion Hub in year 2013, and variability of wind power output that is the same or lower than that observed in about 70% of EWITS sites, are favourable conditions for the hybrid system.

Under such favourable conditions and under policies that motivate CCS retrofits, reducing the CCS capital costs results in integration costs that are lower than those of several energy storage devices. Furthermore, results suggest that reduction in the capital costs of CCS retrofits and amine storage might be more effective in integrating wind power as a source of base-load power than investments or subsidies that directly lower the cost of wind farms.

Also these favourable conditions of price arbitrage opportunities and wind power variability make the hybrid system an attractive alternative to achieve CO_2 emissions reductions from an existing plant, when compared to the option of replacing such existing coal plant with a new base-load NGCC plant with or without an amine-based CCS unit. The CoC of the hybrid system under favourable conditions is lower than that of a new NGCC (although the hybrid system achieves a higher capture rate). Also, retrofitting the existing coal plant with post combustion amine CCS and amine storage, and co-locating an optimally sized wind farm results in lower CoC than the CoC from a systems that uses a new NGCC plant with CCS and an independently operating wind farm, assuming gas prices in the range 6-8 \$/MMBtu (see calculations in section XII in [28]).

It is worth noting that by using a 1-hour time resolution for the operations of the hybrid system we may have underestimated its potential for higher integration of wind power in sites with relatively lower wind power variability (see analysis using 10 minute time intervals in section XI in [28]). Finally, we need to highlight that our analysis did not account for other factors that are likely to increase the benefits of the hybrid system -relative to a stand-alone wind-farm independently operated from the coal-fired plant with CCS, such as: (a) avoided costs from connecting a stand-alone farm to the power transmission system (b) avoided costs incurred by the power balancing authority to mitigate the variability of wind power output (c) benefits from increased ramp-capability of the system. In fact the benefits from avoided transmission costs may be substantial, as they are reported to be in the range of 3.2-14.3 \$/MWh for onshore wind farms with a capacity factor of 34% [31, 33].

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Appendix A. Set of constraints for the linear optimization model

i. The average wind power in every time period dispatched by the hybrid system at all instants of time, should be less than or equal than the installed capacity of the wind farm.

$$\left(O_{w,t}\right) - O_w^{max} \leq 0, \forall\, t \in \{1, \dots, T\}$$

ii. The storage tank should not overflow:

$$\sum_{i=1}^{t} (r_t - 1) \geq -H_S^{max}, \forall\, t \in \{1, \dots, T\}$$

And lean amine solution should not be regenerated:

$$\sum_{i=1}^{t} (r_t - 1) \leq 0, \forall\, t \in \{1, \dots, T\}$$

iii. The scaling factor is given by the maximum value of r_t:

$$SF \geq r_t, \forall\, t \in \{1, \dots, T\}$$

iv. The maximum limit on the hybrid unit's power output fluctuation ($\mathrm{Output}_{variations}^{hybrid}$) must be maintained.

$$-\mathrm{Output}_{variations}^{hybrid} \leq \left(O_{c,t} + O_{w,t} - E_{stripper} * (r_t)\right) - \left(O_{c,t-1} + O_{w,t-1} - E_{stripper} * (r_{t-1})\right) \leq \mathrm{Output}_{variations}^{hybrid}$$

$$, \forall\, t \in \{2, \dots, T\}$$

v. The wind power dispatched should be less than or equal to the available wind power forecast ($O_{w,t}^{available}$) for each time period

$$O_{w,t} \leq O_{w,t}^{available}, \forall \, t \in \{1, \dots, T\}$$

vi. No additional transmission capacity should be required.

$$(O_{c,t} + O_{w,t} - E_{stripper} * (r_t) - E_{other}) \leq O_C^{nameplate}, \forall \, t \in \{1, \dots, T\}$$

vii. The power generated by the coal unit at any time period should be at least as high as the minimum stable power generation level for the coal plant (O_c^{min}).

$$-(O_{c,t}) \leq -O_c^{min} , \forall \, t \in \{2, \dots, T\}$$

viii. The coal plant power output variations between consecutive hours should be within the ramp rate capabilities of the coal plant ($rr_{coal\ plant}$):

$$-rr_{coal\ plant} \leq O_{c,t} - O_{c,t-1} \leq rr_{coal\ plant} , \forall \, t \in \{2, \dots, T\}$$

ix. Non-negativity constraints for all decision variables

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